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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER of the Petition of Greycliff Wind Prime, LLC to Set Terms and Conditions for Qualifying Small Power Production Facility Pursuant to M.C.A. § 69-3-603	UTILITY DIVISION DOCKET NO. D2015.8.64

PREFILED REBUTTAL TESTIMONY OF ROGER SCHIFFMAN ON BEHALF OF GREYCLIFF WIND PRIME, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Roger Schiffman. My business address is 1701 Arena Drive, Davis, CA 95618.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am the managing director of Power Markets Research Group ("PMRG"). PMRG is a private consulting firm specializing in energy markets, resource planning issues, and in calculating estimates of long-term avoided costs. I started that position after seven years with Black and Veatch Corporation in Sacramento, California.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION

A. I received my bachelor of business administration, finance, investment and Banking in 1988 from the University of Wisconsin-Madison. I continued my studies at the University of Wisconsin-Madison working toward a Master of Science in Finance from 1988-May 1990. I left the graduate studies program to join the Wisconsin Public Service Commission, where I became a senior financial analyst.

Q. PLEASE BRIEFLY DESCRIBE YOUR WORK HISTORY

A. Prior to my assignment as manager at PMRG, I was a principle at Black and Veatch and assisted in directing, preparing and developing market analysis, integrated resource planning, nodal market planning, avoided cost, transmission planning, transmission congestion, other transmission issues, resource planning/power supply analyses, and generation reliability analysis. I have provided consulting services in energy market analysis, utility resource planning, and power price forecasting for the last 18 years, at consulting firms including Henwood Energy Services, Navigant Consulting, Ventyx, and Black & Veatch. At each of these firms, I have been responsible for developing long-term projections of electricity prices in U.S. wholesale markets. Those projections have been used in developing estimates of avoided cost, in utility integrated resource planning, and in supporting valuation and due diligence review of purchase and sale transactions for individual power plants, and for portfolios of power plants. At PMRG, I have continued my work on these subject matter areas.

Q. HOW MANY YEARS HAVE YOU BEEN WORKING ON UTILITY RESOURCE PLANNING AND UTILITY RESOURCE/AVOIDED COST ESTIMATES?

A. I have more than 25 years of experience working in the public and private sectors directing, preparing and developing reports and testimony on market analysis, integrated resource planning, nodal markets, avoided cost, transmissions, resource planning/power supply analyses, and generation reliability analysis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by Greycliff Wind Prime, LLC ("Greycliff") to analyze NorthWestern Energy's ("NWE") avoided cost estimates for the Greycliff project located near Big Timber, Montana. I was also retained to create an independent avoided cost forecast which, in my estimation, more accurately captured NWE's long-term avoided cost.

Q. CAN YOU SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND ANALYSIS?

A. Yes. NWE has developed a set of projected avoided costs for its system that it proposes to use as a pricing offer for the purchase of energy from the Greycliff project. PMRG has been asked by National Renewable Energy Solutions, LLC, and Greycliff Wind Prime, LLC, the lead developer of the Greycliff project, to review the NWE avoided cost projections and methodology, and to determine if the approach taken is consistent with industry best practice. The discussion which is set forth below in detail highlights key findings of that review, and also seeks to quantify areas where adjustments to NWE's methodology are appropriate.

Based on the review described below, PMRG has concluded that there are a number of deficiencies in the NWE avoided cost methodology, its specific application to Greycliff, and the data assumptions used. These aspects result in the NWE estimates being below its actual avoided cost for the Greycliff project.

PMRG has developed alternative estimates of avoided cost for Greycliff, based on application of the natural gas price forecast from the U.S. Energy Information Administration – Annual Energy Outlook 2015 natural gas price forecast, and based on use of an alternative fundamental electricity price forecast prepared by the Northwest Power and Conservation Council ("NPCC"). These avoided cost estimates are higher than the values proposed by NWE. PMRG recommends that the value developed using the NPCC forecast be used in determining avoided cost for Greycliff. A summary of the avoided cost estimates prepared by PMRG is listed below in Table 1.

Table 1 – Summary of Greycliff Avoided Cost Projections

Avoided Cost Method	Levelized Avoided Cost ($/MWh)
NPPC Medium Case, with Operating Reserve Adjustments (Recommended Case)	$53.39
NWE with Carbon, with Operating Reserve Adjustments - Adjusted for EIA Natural Gas & Capacity Credit	$80.82

Q. CAN YOU SUMMARIZE FROM YOUR PERSPECTIVE OF THE HISTORY AND REQUIREMENTS OF PURPA AS IT RELATES TO AVOIDED COST?

A. Yes. The concept of Avoided Cost has its roots in the Public Utilities Regularly Policies Act ("PURPA") passed by Congress in 1978. PURPA was instituted when the nation's power generation relied heavily on imported oil that had undergone significant price volatility. Significant increases in the cost of new power plants and the general feel that the traditional utility model was failing to foster an environment of competition also led to general dissatisfaction with the utility model in the United States during the 1970s. Consequently, Section 2(1) of PURPA explained that the purpose of the act was to further the goals of conserving electric energy, increase utility efficiency, and achieve fair rates for utility customers. The concept was to achieve these goals through policies that would foster the development of non-utility cogeneration and small power production.

Under Section 210 of PURPA, a utility is required to purchase electricity from certain nonregulated power producers, termed qualifying facilities ("QFs"). A QF can be either a cogeneration facility meeting certain efficiency requirements, or a small power producer (80

MW or less) whose energy input was primarily from waste, biomass, or renewable resources (the size limitation has since been removed).

PURPA requires utilities to purchase QF power at a nondiscriminatory, just and reasonable rate that does not exceed the purchasing utility's avoided cost. This avoided cost is an upper limit on purchases and is defined in Section 210 (d) as "the cost to the electric utility of the electric energy which but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." A utility's full avoided cost includes incremental costs of electric energy, capacity, or both that, if not for the purchase from the QF, the utility would purchase or generate itself.

Q. PLEASE SUMMARIZE FERC'S GUIDANCE TO STATE REGULATORY COMMISSIONS IN ESTABLISHING AVOIDED COST?

A. The FERC rules implementing PURPA did not select a specific method for establishing the avoided cost rate to be paid QFs but rather left the specific methodology to the discretion of each state. However, FERC has also made it clear that any methodology adopted by the individual states must be consistent with FERC's implementing regulations. FERC also provided certain guidelines to states to consider when developing avoided cost rates. These include:

1. Utilities can be required to pay QFs for the "capacity value" of their projects only when the availability of such capacity allows the utility to reduce its own capacity-related costs by deferring construction of a new plant or by deferring commitments to firm power purchase contracts.
2. Utilities can be required to pay capacity payments even if the QF provides electricity only on an "as available" basis. In such cases, calculation of the payment would be based on a probabilistic estimate of production from a large number of similar QFs.
3. Avoided capacity costs based on a plant designed to displace less efficient generating units must be adjusted to take into account the lower operating costs the utility would incur with the new plant. Thus, if a new plant is deferred by virtue of QF purchases, fuel savings also would be forgone and these "lost savings" should be reflected in the rate paid to the QF.

4. The avoided capacity and energy costs used to calculate QF purchase rates must be internally consistent. For example, to use the high capacity cost of a deferred base load unit and the high energy cost of a peaking unit would exceed the utility's true avoided costs.
5. The just and reasonable rate for new capacity is the avoided cost even when the utility making the purchase is simultaneously making sales to the QF.
6. Rates for QF purchases may be levelized over the term of the obligation as long as the total payments over time do not exceed the estimated avoided cost. Rates may be negotiated at levels below full avoided costs if the QF agrees to the arrangement, presumably in return for some contractual provisions not mandated under the applicable rules in that jurisdiction.

Q. APART FROM THIS GENERAL GUIDANCE, DO FERC'S REGULATIONS PROVIDE GUIDANCE?

A. Yes. 18 C.F.R. § 292.304(e) provides a list of factors that a state Commission must consider when calculating the energy and capacity components of avoided cost rates. These factors include:

1. Avoided cost data submitted by utilities to state regulatory authorities.
2. Availability and characteristics of the QF's power during system peak periods including:
   a. The utility's ability to dispatch the QF
   b. QF reliability
   c. Duration and enforceability of a utility's contract with a QF
   d. Ability to schedule QF outages in coordination with the utility
   e. Usefulness of QF production during system emergencies
   f. Aggregate value of QF capacity and energy on a utility system
   g. Smaller capacity increments and shorter lead times associated with QF capacity
3. The relationship between a QF's production and a utility's ability to actually avoid costs.
4. Costs or savings from changes in line losses as a result of QF purchases.

Q. WHAT HAVE STATES DONE AS FAR AS IMPLEMENTING FERC'S AVOIDED COST GUIDANCE AND REGULATIONS?

A. States have adopted a wide variety of approaches in implementing FERC's directives and in establishing avoided cost methodologies. States have addressed the following conceptual issues:

1. Whether short or long-run marginal costs should form the basis for the avoided cost analysis.
2. The appropriate planning horizon and incremental block of output over which costs are to be measured.
3. The particular methodology used for computing the relevant marginal costs.
4. The treatment accorded to small increments of QF capacity that have no impact individually on a utility expansion plan but that could have an impact if there were a large number of smaller QFs.
5. Treatment of firm versus non-firm QF purchases.

These conceptual issues have been the basis for the varying approaches that Commissions have adopted, including:

1. Long-run marginal cost methods.
2. Proxy unit approaches (in which avoided capacity and energy cost payments are linked to a unit selected to represent the next unit on the system, perhaps without a detailed analysis confirming that the proxy unit is the best fit for the system).
3. Expansion planning analysis (in which avoided capacity and energy costs may be linked to the next unit on the system as identified through a generation expansion planning study).
4. Short-run marginal cost methods.
5. Single unit approaches (generally this involves identifying the unit on the dispatch margin and linking avoided energy cost payments to the production cost of that unit).
6. Incremental heat rate approaches (linking payments to the incremental heat rate on a utility system that may involve more than a single unit).
7. Production costing approaches (using a computer simulation to identify the production cost and avoided cost payments).
8. Purchased power approaches (in which a bidding system may be used to determine the basis for the utility's avoided cost).
9. Reverse-the-meter approaches (in which energy produced is sent to the utility and reverses the meter that registers energy consumption so that the meter records the net energy consumed once QF production is taken into account).
10. Differential revenue requirements approaches (whereby the difference in a utility's revenue requirements are calculated with and without the QF purchase), usually through the use of detailed production cost or market simulation models.

In addition, in some jurisdiction, resources are developed and selected by utilities as a result of competitive RFP and resource solicitation processes. In cases where the process is administered with safeguards that prevent self-dealing or preferential treatment for resources being developed by the subject utility (e.g., the use of an independent evaluator or the adoption or presence of rules precluding offers from the host utility), bid prices submitted through the RFP process may be deemed as representative of the utility's avoided cost and in compliance with PURPA.

Q. HOW HAS THE MONTANA PSC RECENTLY ESTABLISHED AVOIDED COSTS?

A. In 1981, the Montana Legislature enacted "mini-PURPA," which also entitles QFs to sell electricity to electric utilities regulated by the Montana Public Service Commission ("PSC"). The Montana PSC has issued a number of avoided cost rulings in the period since PURPA was enacted. The Montana PSC also adopted FERC's avoided cost and QF rules by reference. The Montana rules require utilities to offer standard rates to QFs, but limit availability of long-term standard rates to QFs no larger than 3 megawatts ("MW"). QFs larger than 3 MW must negotiate agreements with QFs under the revised A.R.M. § 38.5.1902(5), adopted by the Montana Secretary of State on December 24, 2015. As such, the Greycliff project is subject to a negotiated avoided cost, and in fact the Montana PSC ordered Greycliff and NWE to negotiate a long-term avoided cost rate and to attempt to reach agreement on a contract. Negotiations ultimately proved unsuccessful in reaching agreement on all issues as of the end of the negotiation period on March 15, 2016, thereby necessitating Montana PSC resolution of the appropriate avoided cost rate for the Greycliff.

The procedural history and analytic approaches for avoided cost determination used by the PSC in setting standard rates, should also have applicability in setting an appropriate avoided cost estimate for the Greycliff Project. In establishing an avoided cost methodology in Montana, the PSC has in the past utilized a proxy unit method, where avoided costs were established based on the cost of planned coal-fired generators. As NWE's resource plans, and the industry evolved, the proxy unit method transitioned to use the cost of a planned natural gas-fueled combined-cycle resource in establishing NWE's avoided cost. The last time that the PSC used Colstrip 4 as the basis for avoided cost, values were set at \$99.41/MWh On-Peak, and \$51.15/MWh Off-Peak. As the PSC transitioned to use of a NGCC unit in its proxy approach, it established Schedule QF-1 avoided cost rates of \$90.87/MWh On-Peak and \$54.44/MWh Off-Peak. The PSC again revisited avoided cost rates a bit over a year ago, in 2014, in reviewing changes to avoided cost determination proposed by NWE. In that case, the PSC found:

> The Commission finds that the basic methodology used to calculate Option 1 rates has not fundamentally changed since 2010.3 Supra ¶¶ 6-10. In the last two QF-1 proceedings, the Commission estimated NWE's avoided cost by blending projected near-term market prices and the expected cost of owning and operating a natural gas CCCT.

In the 2014 QF-1 proceeding, the PSC also identified concerns it had with NWE's avoided cost methodology. For example, the PSC noted that NWE had concluded just a few months earlier that the acquisition of the 439 MW of existing hydro assets was its least cost resource option, but continued to use a NGCC in its resource plan for estimating avoided cost. The PSC expressed concern that NWE had not provided adequate record evidence to support its avoided cost method and specific projections. The PSC expressed additional concern that a factual basis for differences between NWE QF-1 and QF-2 rates had also not been clearly articulated, and that NWE's proposal for establishing wind integration adjustments to avoided costs was not adequately supported by evidence. Given the evidentiary deficiencies it found in the proceeding, the PSC denied NWE's application, and ruled that previous avoided cost rates, determined less than a year and a half previously at that point in time, remained valid and appropriate. This decision was recently upheld by a district court judge in Montana.

Q. WHAT IS THE CURRENT QF-1 RATE AND HOW DOES IT RELATE TO ESTABLISHING AVOIDED COSTS FOR PROJECTS WITH AN INSTALLED CAPACITY GREATER THAN 3 MW?

A. Table 2 lists NWE's current Schedule QF-1 avoided costs for long-term wind purchases:

Table 2 – NWE Energy Standard Offer Schedule QF-1 Avoided Cost Rates

Option 1(c)	**Option 1 adjustments & conditions**
Duration: 19 months - 25 years	• Contingency reserves - QF opts to self-supply or purchase from NWE. Purchase rate based on CU4 reserve cost applied to QF technology • RECs - non CO2-emitting QFs may retain or convey RECs to NWE. If QF conveys RECs to NWE, rates are adjusted to reflect future CO2 emissions costs NWE incurs for CU4. • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is annually adjusted based on actual cost
Rate:	\$0.05850 per kWh (On-Peak) \$0.05314 per kWh (Off-Peak)
Option 2(a)	**Option 2 adjustments & conditions**
Duration: Up to 25 years	• Contingency reserves - QF opts to self-supply or purchase from NEW. • RECs - QFs retain RECs • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is in accordance with Wind Integration Tariff W1-1. • Contingency Reserves – QF opts to self-supply or purchase Contingency Reserves according to the Contingency Reserves Tariff CR-1.
Rate:	Highest-cost 25 MWh Mid-C purchase each hour less \$1.00/MWh
Option 2(b)	**Option 2 adjustments & conditions**
Duration: Up to 25 years	• Contingency reserves - QF opts to self-supply or purchase from NEW. • RECs - QFs retain RECs • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is in accordance with Wind Integration Tariff W1-1. • Contingency Reserves – QF opts to self-supply or purchase Contingency Reserves according to the Contingency Reserves Tariff CR-1.
Rate:	ICE Mid-C index price in on/off peak periods less \$1.00/MWh

The Option 2 tariffs listed above include Wind Integration charges using NWE's W1-1 tariff, which for projects like Greycliff, that are at least 60 miles away from Judith Gap, the tariff rate is $0.26/kW/Month. At Greycliff's expected nameplate capacity of 25 MW, and expected energy production level of 88,043 MWh/Year, that value translates to a charge of $0.8859/MWh.

The Contingency Reserve CR-1 tariff rate is $10.10/MWh, and appears to apply to 3 percent of hourly integrated generation, and 3 percent of load served by that generation, for a total of 6%, or $0.606/MWh. In total, the Wind Integration and Contingency Reserve charges would result in a reduction in Avoided Cost equal to $1.49/MWh.

While the tariffs listed in Table 2 only strictly apply to QF projects that are 3 MW or lower in capacity, the underlying economics of larger projects, such as Greycliff at 25 MW, have similar economic impacts for the NorthWestern system. The published tariffs also provide some information to developers of new renewable energy projects about what to expect in terms of avoided cost, which has potential to benefit both NorthWestern and its ratepayers, in that new, beneficial projects may get developed. For that reason, I believe the tariff levels listed in Table 2 have relevance and can provide guidance when determining the appropriate avoided cost to apply to the Greycliff project.

Q. WHAT IS THE GREYCLIFF PROJECT AND WHAT IS THE HISTORY OF THIS PROCEEDING?

A. The Greycliff Project is a 25 MW (nameplate capacity) wind project located near Big Timber, Montana. Greycliff's Developers believe that a Legally Enforceable Obligation, ("LEO"), has been established, requiring it to sell all of its output from the Project to NWE, and creating a binding obligation on the part of NWE to purchase all of Greycliff's output. The Greycliff project developers had previously entered into negotiations and developed a draft contract for power sales rates under Montana's Community Renewable Energy Project procedures previously, but the project failed to move forward under that mechanism.

On July 2. 2015, Greycliff sent a letter to NWE requesting a contract. On July 8, 2015 NWE stated it could not enter into negotiations or agree to a contract with Greycliff outside of the competitive solicitation process formerly required by Montana rule. Greycliff thereafter filed a petition to set contract terms and conditions on August 17, 2015, commencing the above-captioned proceeding. After more than 6 months, NWE responded to Greycliff's proposed avoided cost of $53.85/MWH minus $3.50/MWH for integration (effective rate of $50.35/MWH). NWE provided estimates of its avoided cost, through submission of pre-filed testimony in the above-captioned proceeding. Greycliff and the Montana PUC staff issued data requests in response to the NWE testimony. Based on the testimony, and data responses received, PMRG was retained to conduct an evaluation of NWE's avoided cost methodology and avoided cost estimates. Results from that evaluation are discussed below.

Q. WHAT NWE'S LONG-TERM AVOIDED COST ESTIMATE FOR GREYCLIFF IN THIS PROCEEDING AND HOW DOES IT DIFFER FROM OTHER AVOIDED COSTS RECENTLY APPROVED OR UNADJUSTED BY THE MONTANA PSC?

A. PMRG understands, based on NWE's pre-filed testimony dated November, 2015, and including adjustments it later proposed for transmission network upgrade costs, NWE estimated Greycliff's long-term avoided cost as follows:

Table 3 – NWE Energy Proposed Greycliff Avoided Cost – Environmental Attributes Included (Based on November, 2015 Filing)

Variable	Levelized Avoided Cost Impact ($/MWh)
Energy Average Avoided Cost	$42.82
DA Firm vs. RT Price	($2.23)
Interconnection Network Upgrades	($4.54)
Regulation	($0.41)
Spinning Reserves	($0.59)
Supplemental Reserves	($0.95)
Avoided Cost (Offer)	**$34.09**

As shown above in Table 3, NWE proposed a series of "deductions" from avoided cost, due to its view of wind integration and operating reserve requirements associated with Greycliff. The reductions proposed by NWE total to almost 20 percent of the original energy avoided cost estimate. NWE's offer is proposed as a 25 Year fixed price, so there is no indexing to fuel prices or inflation, and NWE apparently believes that its 25-year fixed price will still be a valid number as of 2041.

The avoided cost value for Greycliff, as proposed by NWE, is considerably lower than the standard offer avoided costs available to wind projects 3 MW or less, as identified earlier in Section 3. Similarly, the proposed deductions for wind integration and operating reserves are considerably larger than the values outlined in the tariff for standard offer QFs. NWE's avoided cost for Greycliff is also approximately $20/MWh below the value for the Greenfield project, set at $53.99/MWh, which was the last QF project that was subject to negotiated rates, and approved by the PSC.

Q. WHAT IS THE METHODOLOGY REPORTEDLY EMPLOYED BY NWE TO PRODUCE ITS AVOIDED COST ESTIMATE FOR THE GREYCLIFF PROJECT?

A. I base my understanding of NWE's approach to calculating an avoided cost for Greycliff on the description of the approach as outlined in Response Testimony filed by Witnesses LaFave and Hanson, before the Montana Public Utilities Commission in Docket D2015.8.64, *QF Petition from Greycliff Wind Prime, LLC to Set Terms and Conditions.*

NWE describes its approach as a differential revenue requirements method, where it completes a power system simulation using the PowerSimm model. NWE states that it simulated operation of its power system with and without inclusion of the Greycliff project. NWE then states that it examined changes in the net energy balance on its system, and assigned value to output of Greycliff. As described, in assigning value to Greycliff energy production, NWE differentiated between time periods when its system energy balance was in surplus or deficit. As described by Witness Hanson, the following differentiation was applied:

- For periods when Greycliff produces and delivers energy when NWE's supply portfolio is short (i.e., when generation is less than load), Greycliff energy production is assigned the market purchase price for electricity that NWE would otherwise have purchased.
- For periods when the project produces and delivers energy when NWE's supply portfolio is long (i.e., when generation is greater than load) and the market price is higher than the variable cost of Colstrip Unit 4 ("CU4"), Greycliff energy production is assigned the variable cost of CU4. NWE states that this approach is appropriate, because in its view, CU4 is the supply resource that would be backed down, or reduce output to account for the Greycliff production.
- For periods when the project produces and delivers energy when NWE's supply portfolio is long and the market price is lower than the variable cost of CU4, Greycliff energy production receives the price NWE would receive for selling excess energy in the market.

As noted above, in their testimony, NWE witnesses LaFave and Hanson refer to the NWE approach as a differential revenue requirement method. Mr. Hanson also describes the avoided cost approach as relying upon hourly calculations and precision. For example, Mr. Hanson states:

> PowerSimm™ models the effect of changes to NWE's energy supply portfolio and allows for analysis of potential additional resources. PowerSimmTM first calculates the hourly dispatch of NWE's supply portfolio and then compares the Greycliff energy production to that supply portfolio. Only after this comparison is made can the value of the Greycliff wind resource be calculated.

Mr. Hanson later states:

> The PowerSimmTM modeling output contains the market purchases and sales for the portfolios with and without Greycliff. A comparison of the two portfolios determines, by hour, if Greycliff's estimated production offsets market purchases when NWE's supply portfolio is short or creates excess sales when the portfolio is long. Greycliff's production that offsets purchases is multiplied by the corresponding market purchase price to determine the amount paid to Greycliff. Production that offsets excess sales volumes is multiplied by the corresponding CU4 variable cost during times when the market sales price is higher than the variable cost of CU4 to determine the amount paid to Greycliff. Production from Greycliff during times that the portfolio is long and the market sales price is lower than the variable cost of CU4 is multiplied by the price NWE would receive in the market for energy sold. The hourly values of Greycliff's production are then summed for each year to determine Greycliff's total annual energy and capacity rate. The net present value of these annual rates is then calculated and levelized over the average yearly production for the Greycliff project to determine the proposed avoided cost rate for this project.

Consequently, as described by Mr. Hanson, the NWE avoided cost approach models the impact of Greycliff upon the NWE power system, on an hourly basis, and examines the differential with and without Greycliff in estimating avoided cost.

As further described by Mr. Hanson, the PowerSimm model relies upon externally produced forecasts of fuel prices, including natural gas prices, forecasts of electricity demand on the NWE system, and forecasts of available generating capacity and operating characteristics for NWE power plants. Most importantly, the model also relies upon an externally produced forecast of electricity prices. In its testimony and analysis, NWE provides only a cursory description of PowerSimm, so the inner workings of the model are not at all transparent. This aspect critically limits the ability to analyze NWE's avoided cost methodology, and its specific projections for Greycliff.

Q. WHAT CONCERNS, IF ANY, DO YOU HAVE OF THE METHODOLOGY EMPLOYED BY NWE TO CREATE AN AVOIDED COST ESTIMATE FOR THE GREYCLIFF PROJECT?

A. As described in NWE'S testimony, and in responses made by NWE to data requests submitted by Greycliff and by the PSC, NWE describes a number of data assumptions it made that underlie its avoided cost methodology and projections. In reviewing the fundamental data assumptions used by NWE, there are a number of areas where the approach, and specific assumptions chosen, tend to reduce or suppress estimated avoided cost levels.

Q. WHAT AREAS OF CONCERN HAVE YOU IDENTIFIED?

A. First, what NWE describes as a Differential Revenue Requirements Method is in reality not a Differential Revenue Requirements Method as that method has been traditionally understood. While NWE describes its approach as an application of the Differential Revenue Requirements Method, and states that it is the most accurate way to measure avoided cost, the actual application of its approach is quite different from a Differential Revenue Requirement Method. Typically, application of the Differential Revenue Requirements (DRR) avoided cost approach normally involves running detailed, fundamentally based production cost simulation models, both with and without the QF resource on the host utility system. The approach is also sometimes referred to as "QF-In/QF-Out." It is true that this approach has been referred to as the most accurate way to measure avoided cost.

The reason that this approach is used, and sometimes preferred, is because it captures the changes in system dispatch and in underlying cost to produce energy, on a system basis, when a QF resource is introduced onto a power system. The approach was adopted in cases where large amounts of QF resources were being developed on target utility systems, or where the types of QF resources being developed had significantly different operating and cost profiles. In cases such as that, capturing the interaction with other generation on the system can have important implications for measuring avoided cost and for determining the value a particular QF brings to a host utility. An example of a cases where use of this approach could be important would be in assessing avoided cost for a large cogeneration facility, where the efficiency of the underlying resource brings energy cost savings to the host utility, but where the must-run energy production profile of the resource, and associated must-take energy purchases from the host utility, have implications for overall costs, and also for dispatch of other generation on the system. The key focus of the DRR method is to measure the changes in power system production costs, in a more precise way.

Q. HOW DOES NWE'S AVOIDED COST METHODOLOGY DIFFER FROM A DRR METHODOLOGY?

A. In NWE's avoided cost approach, while the utility states that it conducted QF-In/QF-Out simulations, it did not use the PowerSimm model to measure changes in production cost with and without the Greycliff project. In contrast, NWE apparently completed PowerSimm simulations with and without Greycliff, and used that information to tabulate whether it is in a net purchase or a net sales position, on a monthly basis. Then NWE took the additional step, external to the simulation, of applying a combination of forecast monthly energy prices, and/or production cost estimates for Colstrip Unit 4, to the monthly forecast production of Greycliff. NWE limited its use of the PowerSimm model only to estimate whether its system would be in a net purchase or net sale position, on a monthly basis, segmented by High Load (On-Peak) and Low Load (Off-Peak) periods. NWE also used the PowerSimm model to develop long-term market price projections at Mid-C.

By not using the PowerSimm simulations to assess production costs differences on its system, with and without Greycliff, NWE departs fundamentally from the DRR approach. It is unclear why NWE did not use PowerSimm to evaluate avoided cost for Greycliff or the net short/sales position on its system on an hourly basis, which is the primary intent of a DRR approach. Instead, NWE rolls up hourly results to calculate net purchase/sales position monthly, on-peak and off-peak, and then applies forecast prices at Mid-C to Greycliff, or in some instances, the production cost of Colstrip Unit 4. Because NWE chose to apply its method based on monthly results, there appears to be little real value of assessing its system with and without Greycliff. In examining the monthly simulation results, NWE is almost always in a net purchase position. As such, it applies the forecast Mid-C price to Greycliff output in all On-Peak periods, and in most Off-Peak periods. Despite NWE's description of its avoided cost methodology as DRR, the application of this methodology is essentially the same as that used by the PSC in developing avoided cost under the Schedule QF-1 tariff, Option 2(b). NWE is, in reality, not performing a DRR at all, but instead applying the forecast Mid-C price to Greycliff output.

Q. WHAT OTHER CONCERNS, IF ANY, DO YOU HAVE REGARDING NWE'S AVOIDED COST METHODOLOGY IN THIS PROCEEDING?

A. Another concern is that NWE's avoided cost methodology, in determining net purchase and sale periods, violates economic dispatch principles. As described above, NWE assigns market prices to Greycliff output when it is in a net purchase position, and when it is in a net sales position and the market price of energy is below the variable operating cost of Colstrip Unit 4. In cases where it is in a net sales position and the market price of energy is higher than the variable operating cost of Colstrip, NWE states that it assigns the variable cost of Colstrip 4 to energy production from Greycliff, because in its view, Colstrip generation would be reduced under those conditions to accommodate generation from Greycliff.

The approach taken here by NWE violates economic dispatch principles, and artificially suppresses estimated avoided cost. If Colstrip 4 is in the money, meaning its production costs are lower than the market price of energy, then there is no need to reduce its output during times when Greycliff is generating. Greycliff's dispatch cost will be zero, as the energy is taken whenever produced. Both Colstrip 4 and Greycliff will be in the money under this type of circumstance, so the prudent decision by NWE would be to sell additional energy into the market. Reducing CU4 generation when it is in the money, would cause NWE to forgo off-system sales revenue and operating profit, and would be against its ratepayer and shareholder interests. This aspect of the NWE avoided cost methodology should be changed, and Greycliff production should be assigned the market price during all of these situations. The approach taken by NWE is artificially suppressing its avoided cost estimate.

Q. HAVE YOU SEEN DATA SUGGESTING THAT NORTHWESTERN IS ACTIVE IN BOTH PURCHASING AND SELLING ENERGY IN THE WHOLEALE MARKET?

A. Yes. NorthWestern consistently purchases and sells energy in the wholeale power market, both in its Montana operations and in its South Dakota operations. Table 3 below shows NorthWesterns market purchase and sale history, as reported through the FERC Form 1. These data were extracted by PMRG from the Energy Velocity datasource. As shown, NorthWestern routinely and consistently engages in both power sales and purchase activity in the wholesale power market.

Table 3 – NorthWestern Energy Purchase and Sales Data

	2010	2011	2012	2013	2014	2015
Power Purchases (MWh)	6,790,265	5,936,248	5,971,881	6,762,934	7,013,369	4,752,672
Energy Charges ($)	$299,843,946	$255,317,849	$252,484,353	$311,119,417	$304,822,900	$231,825,119
Demand Charges ($)	$19,457,729	$9,899,498	$12,917,081	$10,441,580	$11,166,832	$12,527,973
Total Charges ($)	$319,262,816	$265,180,449	$265,206,353	$321,523,916	$315,957,355	$244,320,023
Energy Charges ($/MWh)	$44.16	$43.01	$42.28	$46.00	$43.46	$48.78
Total Charges ($/MWh)	$47.02	$44.67	$44.41	$47.54	$45.05	$51.41
Power Sales (MWh)	2,446,738	1,398,453	1,429,602	1,965,449	2,425,078	3,522,568
Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Demand Revenue ($)	$0	$0	$0	$0	$0	$0
Total Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Energy Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08
Total Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08

Q. WHAT OTHER ISSUES HAVE YOU IDENTIFIED, IF ANY, REGARDING NWE'S AVOIDED COST METHODOLOGY IN THIS PROCEEDING?

A. Another concern I have is that NWE's avoided cost methodology is not transparent and is difficult to assess, given the information Greycliff has been provided. As described, NWE states that it uses a forward electricity and natural gas price strip, and building from those price strips, the PowerSimm model develops prices and simulates operation of its system. Mr. Hanson, in his testimony, refers to updating the natural gas and power price forecasts relative to NWE's 2013 Electricity Supply Resource Procurement Plan. In his testimony, Mr. LaFave states that "the Greycliff model uses an Energy Information Administration escalation rate instead of the escalation rate included in NWE's 2013 Electricity Supply Resource Procurement Plan."

Neither Mr. LaFave nor Mr. Hanson provide any details about the development of the natural gas or power price curves, or about the simulation process used by PowerSimm to translate historical prices into a forecast of future or forward power prices. The natural gas and power price curves were not provided to Greycliff with the pre-filed testimony, but instead were provided in response to Greycliff data requests. The process for deriving those curves was not detailed, and the workpapers similarly were not detailed enough to review or replicate the derivation.

PMRG also reviewed information available on the Ascend Analytics (Ascend) website. Ascend is the developer of the PowerSimm model. In data responses, and phone conversations, NWE revealed that Ascend had been involved in completing the PowerSimm simulations, and that output data from the simulations resides on computer servers in the Ascend offices. The Ascend website refers to use of stochastic modeling, and a mean-reversion algorithm for PowerSimm, but also provides very little detail, and no characterization of how stochastic parameters are derived or used in the model.

To develop some understanding of the NWE PowerSimm simulation, PMRG also reviewed documentation surrounding NWE's 2013 Electricity Supply Resource Procurement Plan. In supporting documents related to that Plan, NWE refers to stochastic modeling of natural gas prices, power prices, hydro production, electricity demand, renewable production, and generator outages. Based on that discussion, the inference is that NWE followed a similar approach in developing its Greycliff avoided cost estimates, but with updated input price curves for natural gas and Mid-C electricity prices.

However, in its Greycliff testimony and data responses, NWE does not discuss the stochastic nature of the PowerSimm model, and does not provide any information about the algorithms used, the specification of probability distributions and correlation and covariance statistics, or other key input data and algorithms that play a pivotal role in the PowerSimm simulation environment. This is critical information to omit, because the specification of volatility and correlation parameters plays a key role in influencing the dispatch results, and especially the projected power prices.

Q. WHAT DID YOU FIND, IF ANYTHING, WITH RESPECT TO NWE'S SELECTION OF A PARTICULAR MID-C INDEX.

A. Generally speaking, NWE's Selection of Mid-C Historical Price Series departs from the Montana PSC's direction to NWE to use the InterContinental Exchange ("ICE") prices at Mid-C. NWE's departure from the PSC's directions results in understating electricity prices and therefore also understates NWE's voided costs.

In its prior avoided cost determinations, the PSC has referenced the ICE prices series for use in developing power price and avoided cost estimates based on Mid-C. In its workpapers supporting the Greycliff avoided cost projections, NWE used Powerdex data rather than the ICE data. This choice results in characterization of historical prices that are materially lower than prices reported by ICE. Figures 1 through 3 below provide a comparison of reported prices at Mid-C, based on the ICE data series compared to NWE's Powerdex series. As shown, the Powerdex data used by NWE result in lower prices, and reduced volatility, compared to the ICE series. For example, in On-Peak periods, Powerdex has averaged $3.68/MWh lower than ICE. In Off-Peak periods, Powerdex has averaged $0.89/MWh lower. Across all hours, Powerdex has averaged $2.48/MWh lower than ICE.

Because NWE's avoided cost projections rely upon the historical and near-term projected natural gas and power prices, through specification of volatility parameters and of forward strip prices, use of an understated historical series also results in understated forward prices. Figures 1 through 3 illustrate differences between the Powerdex and ICE historical prices.

Figure 1 – Comparison of ICE and NWE Mid-C Historical Electricity Prices (On-Peak)

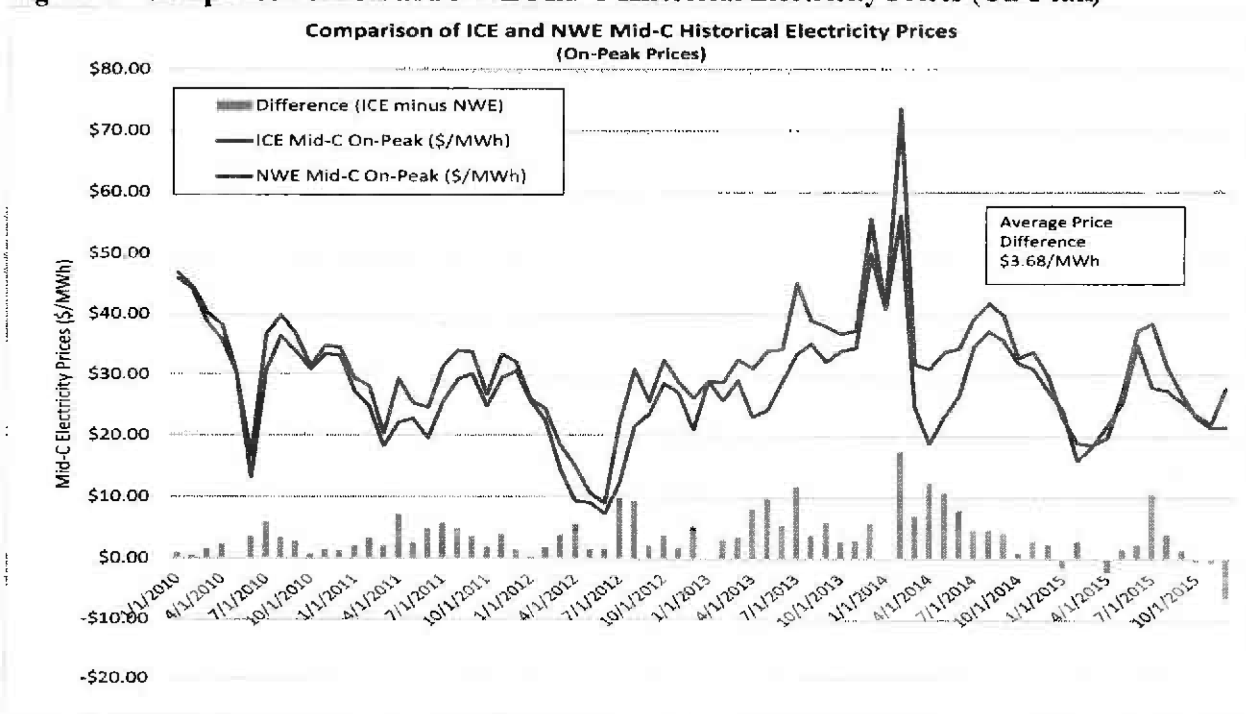


Figure 2 – Comparison of ICE and NWE Mid-C Historical Electricity Prices (Off-Peak)

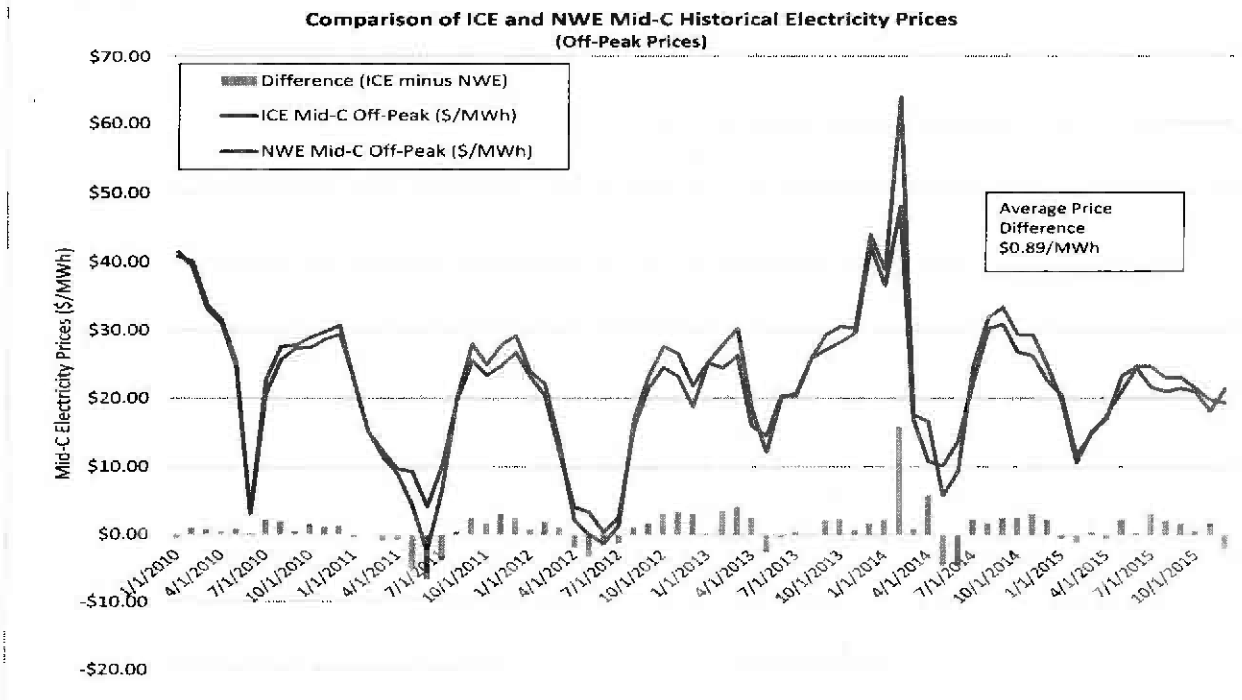
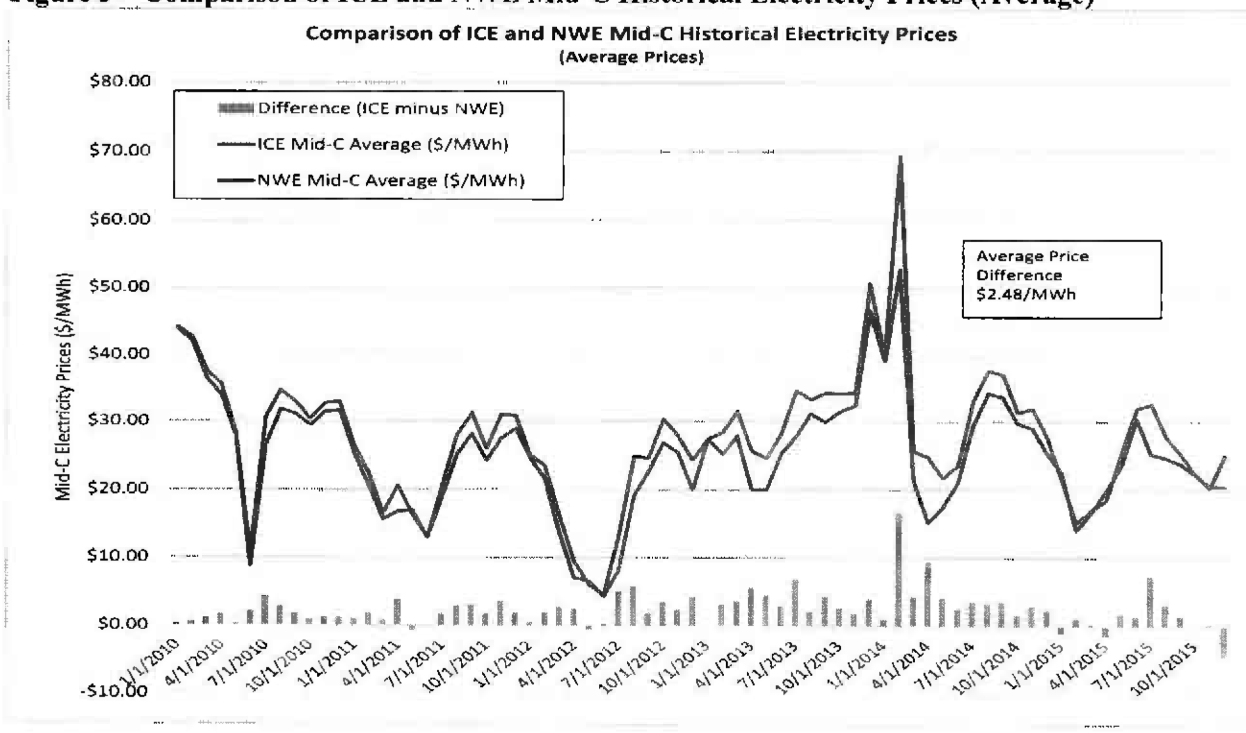


Figure 3 – Comparison of ICE and NWE Mid-C Historical Electricity Prices (Average)



Q. WHAT CONCERNS, IF ANY, DO YOU HAVE REGARDING NWE'S RELIANCE UPON HISTORICAL AND FORECAST NATURAL GAS PRICES IN CALCULATING AN AVOIDED COST FOR GREYCLIFF?

A. In NWE's avoided cost methodology, it relies upon historical and forecast natural gas prices at the AECO hub in Alberta, for its assessment of natural gas prices in the PowerSimm and other modeling. The PSC has similarly relied upon AECO natural gas prices in establishing avoided cost rates under the standard offer provisions (QF-1), and in reviewing past avoided cost analysis submitted by NWE. However, as both NWE and the PSC have focused on the Mid-C trading hub as a proxy for electricity market prices, the reliance upon the AECO hub should be reconsidered.

In developing avoided cost estimates for NWE, natural gas prices are critically important. That is true because in the Western U.S. power markets, generators fueled by natural gas typically establish market clearing energy prices over 90 percent of the hours each year. The linkage of natural gas and electricity prices at Mid-C will become even stronger with planned retirement coal-fueled generation in the region.

In focusing on power prices at Mid-C, and developing forecasts of future power prices at that trading hub, it is important to match the natural gas price series being used, to the actual fuel source of the underlying natural gas-fueled generation in the area. If there is a mismatch, then evaluation of historical and projected power prices will be distorted, and resulting avoided cost estimates will be inaccurate.

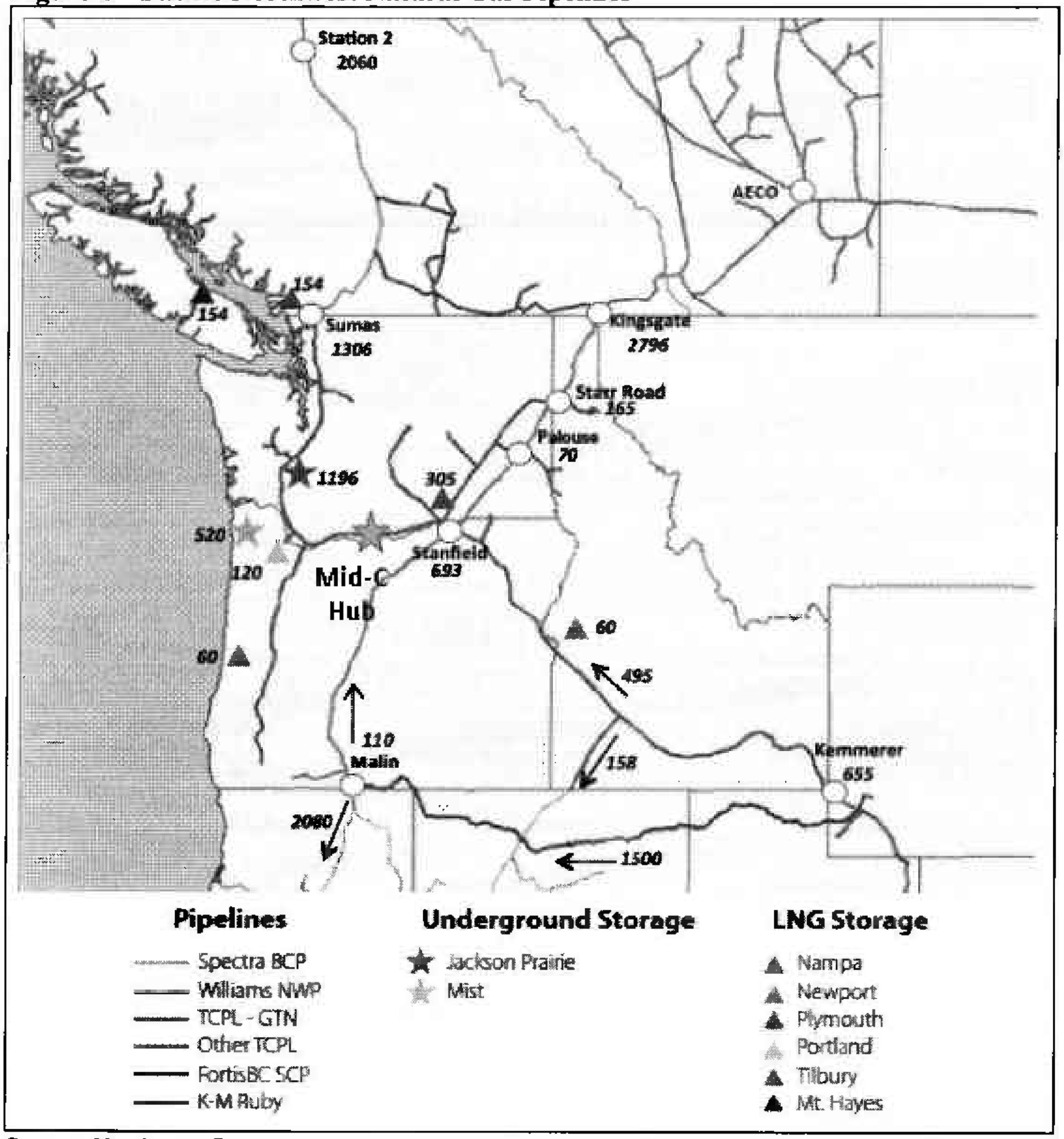
Figure 4 below provides an illustration of major natural gas pipelines in the Pacific Northwest region, including Alberta and British Columbia. As shown, there are three main pipeline routes bring natural gas into the Northwest, including:

- **The Other TCPL Pipeline** network collects natural gas in Alberta, and delivers it to the Western U.S. at Kingsgate, and also delivers natural gas to the Alliance Pipeline, which transports gas to the Midwest U.S.

- The **TCPL-GPN Pipeline** brings natural gas from Alberta, through Kingsgate. This pipeline also transports significant quantities of Alberta natural gas east and South to the Midwest U.S., through the Alliance Pipeline
- The **Williams NWP Pipeline** brings natural gas from British Columbia at Sumas, and from the Rockies Basin, and also connects with Alberta gas at Kingsgate. It transports natural gas throughout the Pacific Northwest, and into California
- The **Spectra BCP Pipeline** brings natural gas from British Columbia to Sumas.
- The **Williams NWP and TCPL-GPN** pipelines intersect at Stanfield, which is a key pricing hub in the Pacific Northwest.

Figure 4 lists key pipeline facilities, natural gas storage facilities, and natural gas pricing hubs. They key hubs located within the region are Stanfield, Kingsgate and Sumas. Malin is located in Southern Oregon, where natural gas pipelines also intersect, and where natural gas flows into Northern California. The AECO hub is northeast of the region. As shown in Figure 4, natural gas supply in the Pacific Northwest originates not just in Alberta, but also in the Rocky Mountain region, and in British Columbia. The chart lists key facilities, and also lists maximum flow capacity on those facilities.

Figure 4 – Pacific Northwest Natural Gas Pipelines



Source: Northwest Gas Association

There is currently 8,700 MW of natural gas fueled generation in the Pacific Northwest, including a number of efficient natural gas-fueled combined cycle plants. Most of the natural gas fueled generation in the region takes natural gas from the Williams NWP Pipeline. Table 4 lists estimated generating capacity and natural gas fuel use for electricity generation in the region.

Table 4 – Natural Gas Use by Pacific Northwest Power Plants

Pipeline	Primary Natural Gas Supply Sources	Natural Gas Fueled Generation Capacity (MW)	Gas Volume (Dth/Day)	Gas Volume (% of Total)	Gas Capacity (Bcf/Day)	Gas Capacity (% of Total)
Spectra BC	British Columbia	515	127,069	7%	0.13	7%
TCPL - GTN	Alberta	2,774	505,577	30%	0.51	30%
Williams NW Pipeline	Rockies, British Columbia, Storage	5,133	1,076,281	63%	1.07	63%
Total		**8,422**	**1,708,927**	**100%**	**1.70**	**100%**

Data Source: Northwest Gas Association & Pacific Northwest Utilities Conference Committee (PNNUC.org)

As shown in Table 4, approximately 30 percent of the natural gas-fueled generation in the Pacific Northwest takes fuel from the TCPL-GTN pipeline, which is the most direct connection to Alberta.[1] In contrast, 63 percent of the fuel consumed by power plants in the Northwest region take fuel from the Williams NWP Pipeline, and 7 percent takes fuel from the Spectra BC Pipeline. Fuel from the Williams NW P Pipeline is sourced primarily in the Rockies and British Columbia. The Williams line is also connected to key natural gas storage facilities in the region, which are used to manage supply during high demand periods.

At Mid-C, the closest natural gas pricing point is at Stanfield. That is also the point where the major natural gas pipelines in the Pacific Northwest intersect. As such, natural gas pricing reported at Stanfield reflects a blended combination of natural gas supply basins, and more accurately reflects the underlying use of natural gas in the region, including usage by electric generators. PRMG recommends that the Stanfield pricing hub be used as the appropriate basis

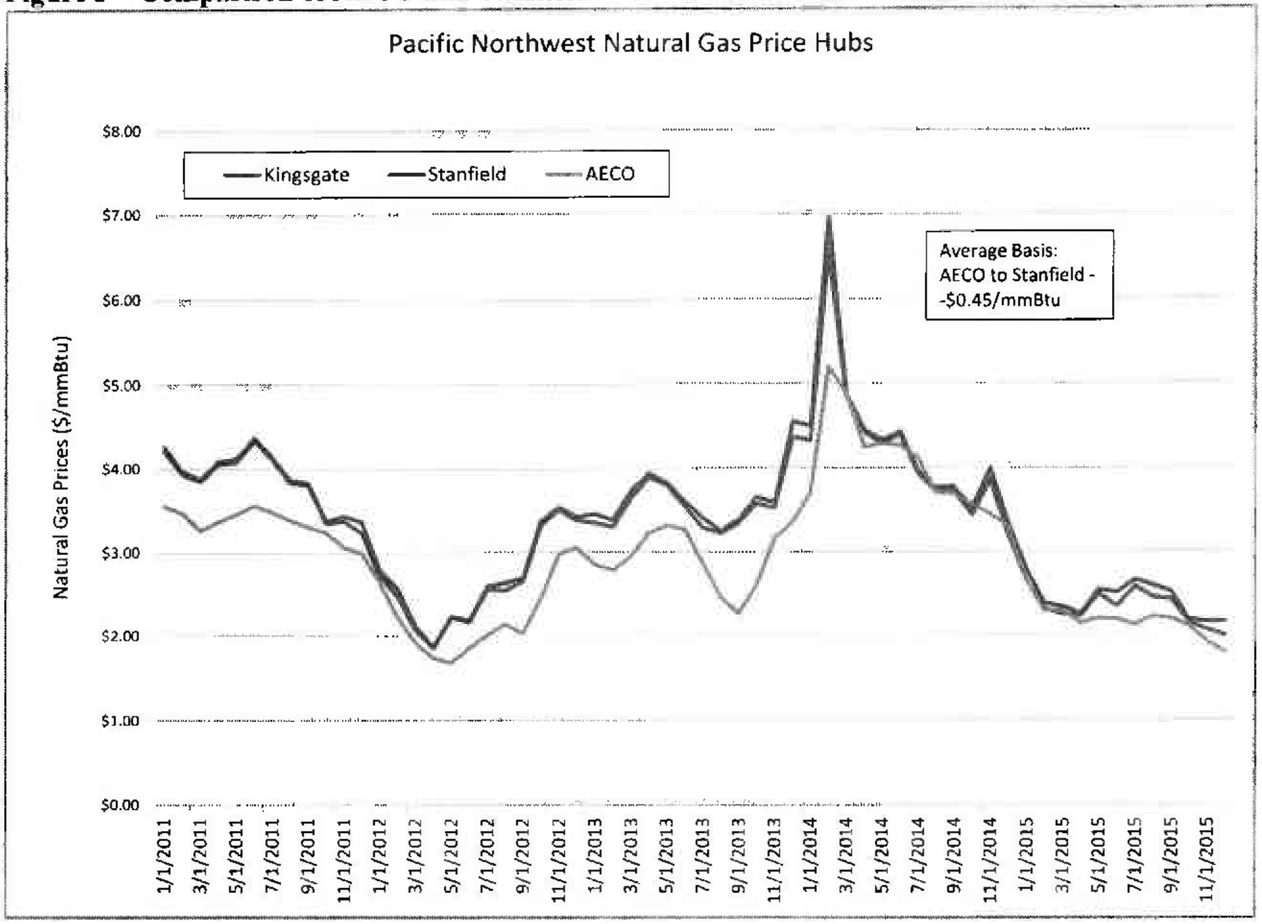
[1] This value is also consistent with date on the production and disposition of natural gas in Canada. On a monthly average basis, natural gas production in Alberta is 3,875 mmcfd. Production in British Columbia averages 495 mmcfd. Exports of Canadian natural gas to the West Coast of the U.S., averages 1,100 mmcfd, on a monthly basis. As such, about 25 percent of the daily natural gas production in Alberta and British Columbia is transported to the Pacific Northwest. The remaining 75% of the gas produced in Alberta and BC is consumed in Canada, or exported to the U.S. at other points, such as Chicago.

for forecasting natural gas prices and for determination of electricity prices at Mid-C, and for purposes of developing NWE avoided cost projections.

Q. HOW DOES NWE'S RELIANCE ON AECO MARKET HUB AFFECT NWE'S AVOIDED COST ESTIMATES FOR GREYCLIFF?

A. NWE'S use of AECO results in a significant understatement of natural gas prices and also electricity prices at Mid-C, which results in an understatement of NWE's actual avoided costs. To explain, given that Stanfield is a more appropriate pricing point for natural gas prices and resulting electricity prices at Mid-C, it is important to understand price differences between the two points. Based on historical natural gas prices, the use of the AECO pricing hub understates prices at Mid-C by at least $0.45/mmBtu. Using an average market heat rate of 10 MMBtu/MWh, the understatement of natural gas prices results in understatement of Mid-C electricity prices of $5.00/MWh, and understatement of NWE avoided cost by that same amount. This further highlights the need to utilize Stanfield as the correct natural gas pricing hub for use in NWE's Montana avoided cost determination. A comparison of historical natural gas prices at the AECO and Stanfield locations is shown in Figure 5.

Figure 5 – Comparison of AECO and Stanfield Historical Natural Gas Prices



Q. WHAT CONCERNS, IF ANY, DO YOU HAVE ABOUT POWERSIMM AS IT IS EMPLOYED BY NWE IN THIS PROCEEDING?

A. As discussed above, NWE utilized the PowerSimm simulation model to develop its forecasted electricity prices at Mid-C, and its resulting avoided cost for Greycliff. The PowerSimm model relies upon near-term forward natural gas and electricity prices, and statistical relationships between fundamental variables, to develop long-term stochastic forecasts of natural gas and power prices, and of NWE system operations. While NWE provides no discussion of its stochastic modeling, or specification of the statistical parameters used, presumably statistical parameters were developed using historical data on fuel prices, electricity prices, electricity demand, hydro production, wind production, generator outages, and other relevant variables.

Statistical relationships are only valid in forecasting if the underlying processes that are being modeled, remain stable and unchanging. If the processes are undergoing structural change, then results from statistical modeling are invalid and inaccurate. PMRG has already documented that NWE utilized a historical power price series that understates electricity prices at Mid-C, and a historic and projected set of natural gas prices, based on AECO, that understates natural gas prices at Mid-C.

In the current fuel and power markets, the underlying processes that form prices are rarely stable and unchanging. To the contrary, those price formation processes are fundamentally based, and are undergoing substantial structural transformation. Moreover, that transformation will continue for the foreseeable future. There are a variety of factors contributing to structural change in the fuel and power markets:

- The advent of shale gas production has fundamentally changed the supply dynamics of natural gas, the cost of production/extraction, and is also fundamentally changing natural gas basis differentials compared to historical price levels
- U.S. EPA environmental policies to reduce hazardous air pollutants, regional haze, Nitrogen Oxide, Sulfur Dioxide, and Carbon Dioxide, are having a significant impact on the electric generation supply mix, and are causing the retrofit and/or retirement of a substantial number of coal-fueled generators.
- The wide-scale penetration of wind and solar resources in the Western U.S. and in Eastern U.S. states as well, are further altering the economics of power generation, the underlying composition of the supply mix, and the operation of fossil resources.
- Lower natural gas prices, more economic construction costs, and lower emissions from natural gas-fueled generation relative to coal-fueled resources, is driving a substantial increase in the demand for natural gas for use in electricity generation. In virtually all long-term projections, natural gas use for electricity generation is the largest projected component of demand growth for that fuel.

These factors all point to increased demand and prices for natural gas, which will further increase the correlation between natural gas and electricity prices at Mid-C, but will also alter the underlying statistical relationships between fuel and electricity prices in the region, and between those prices and other key fundamental variables. A statistical model such as PowerSimm is not able to fully or accurately capture the fundamental changes occurring in the fuel and power markets, due to its reliance upon historical statistical relationships. Instead, it is necessary to utilize a fundamental simulation model to fully capture the changing dynamics of the industry. For this reason, virtually all major consulting firms that develop long-term fuel and power price forecasts, utilize structural simulation models, for developing forecasted natural gas and electricity prices. This includes firms such as Ventyx, Navigant Consulting, ICF, Pace Global, and Black & Veatch. Given the strong growth in natural gas demand anticipated due to environmental regulation affecting the power industry, using a statistically based model such as PowerSimm, is likely to materially understate the underlying fundamental natural gas and energy price levels in the market.

Q. HOW HAS NWE UNDERSTATED FUTURE GAS PRICES?

A. In reviewing PSC Orders on avoided cost methodology and price levels, there has been considerable discussion by the PSC and others about the approaches taken by NWE resulting in understated natural gas price forecasts. Several times in recent avoided cost cases, the PSC has rejected NWE's natural gas price forecast, based on conclusions that it was well below other forecasts in the industry. The PSC has directed that forecast natural gas prices from the EIA Annual Energy Outlook ("AEO") be used in developing avoided cost estimates, or at minimum, that nominal escalation rates developed from the AEO forecast be used. In developing the Annual Energy Outlook, EIA utilizes a long-term fundamentally based model.

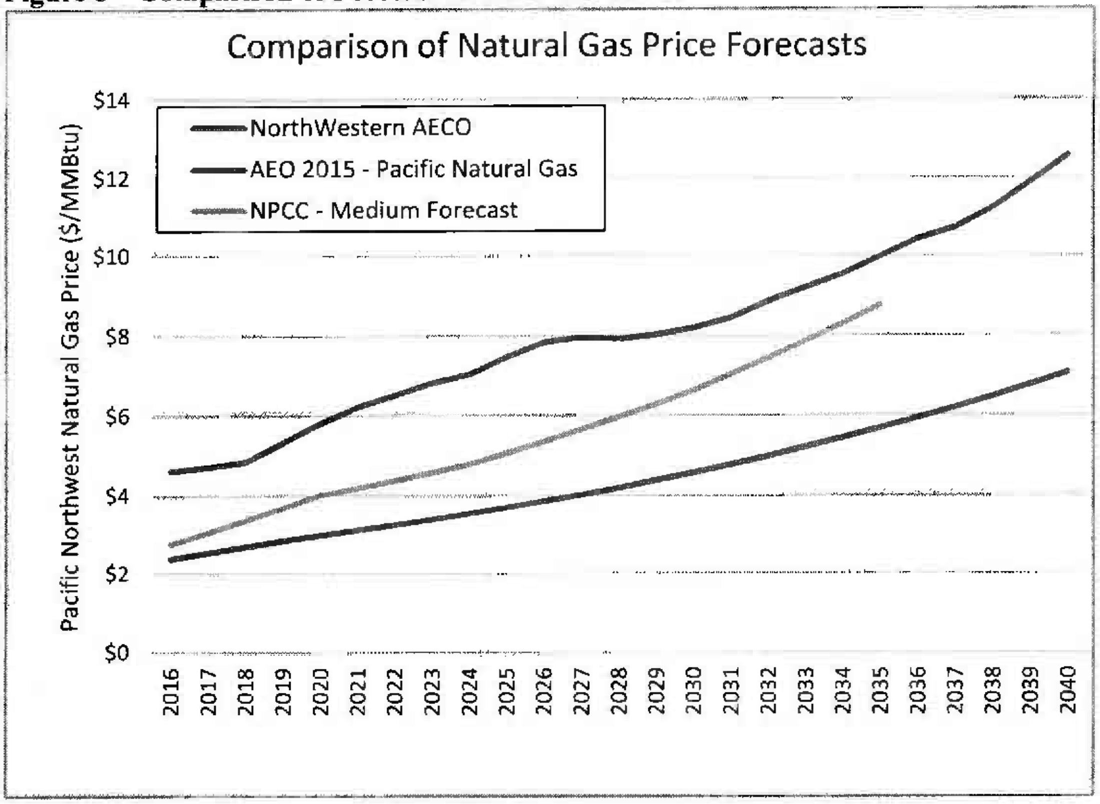
In developing Greycliff avoided cost estimates, NWE utilized a near-term forward price strip, and then applied escalation rates from the AEO 2015 forecast. In applying escalation, NWE appears to have applied an annual compound rate of growth of 4.41 percent. It applied that same growth rate to forecast power prices at Mid-C.

As alternative forecasts to compare against, PMRG obtained the Pacific natural gas price forecast for electricity generation from the AEO 2015 forecast. PMRG also obtained a natural gas price forecast prepared by the Northwest Power Planning and Conservation Council ("NPCC"). NPCC arose from the 1980 Northwest Power Act, which authorized Idaho, Montana, Oregon, and Washington to develop a regional power plan and fish and wildlife program to balance the Northwest's environment and energy needs. The heart of the NPCC's mission is to preserve the benefits of the Columbia River for future generations. NPCC recently completed its 7th Power Plan for the region, and it is a respected source of industry planning information in the Pacific Northwest.[2] The development of NPCC's forecast is done independently, so PMRG views it as an objective source of forecast information for use in the Greycliff avoided cost determination.

Figure 6 provides a comparison of the NWE natural gas price forecast, the EIA AEO 2015 natural gas price forecast, and the medium range natural gas price forecast developed by NPCC. As shown, the forecast developed by NWE is well below the AEO 2015 price forecast. NWE's forecast is also much lower than the natural gas price forecast developed by NPPC. The NPCC forecast is more reflective of stronger demand growth anticipated for natural gas in the electricity generation sector.

[2] The full report, and documentation can be found at http://www.nwcouncil.org/energy/powerplan/7/plan/

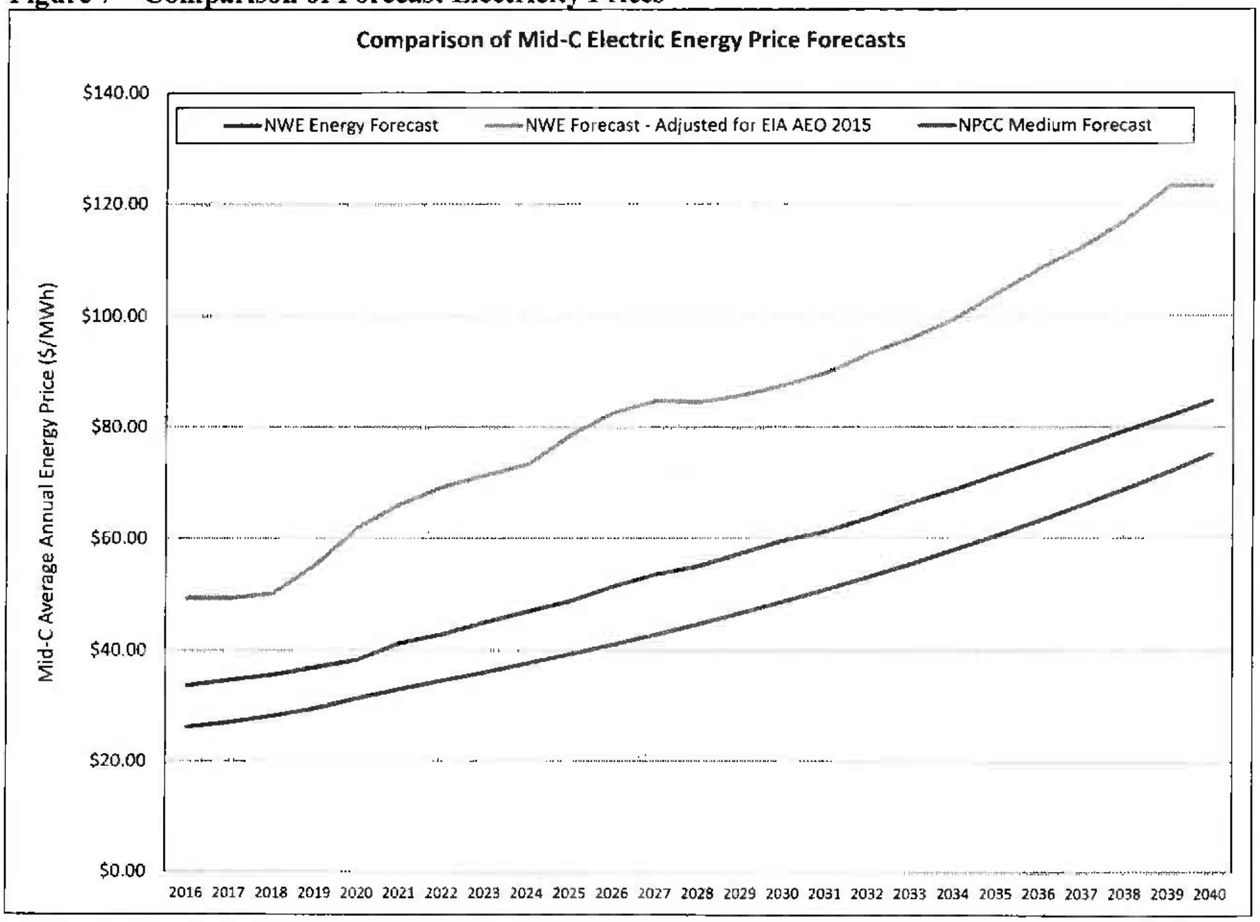
Figure 6 – Comparison of Forecast Natural Gas Prices



Q. WHAT ALTERNATIVE FORECAST DO YOU PROPOSE TO UTILIZE IN THIS PROCEEDING IN ORDER TO DEVELOP AVOIDED COST RATES FOR GREYCLIFF?

A. The NPCC's electric price forecast from its Seventh Power Plan because it is objective, rigorous, transparent and utilizes best industry practices. The NPCC is a well-respected organization in the Pacific Northwest, and one of its goals is to develop independent and objective power plans and policy analysis for the region. NWE relied upon the NPCC forecast and analysis in some of its resource planning efforts. NPCC developed it Seventh Power Plan using rigorous analytic approaches, and a detailed set of fundamental analyses. Its forecast is also transparent, and utilizes industry best practice modeling techniques. NPCC uses the Aurora XMP fundamental simulation model to develop the electricity price forecast. The NPCC forecast reflects recent declines in natural gas prices, but also reflects the structural changes that the power industry is undergoing, and fundamentally reflects those changes in development of its natural gas and electricity price forecasts, and in its underlying resource plan for the Northwest region.

Figure 7 – Comparison of Forecast Electricity Prices



As Figure 7 compares the NWE forecast of energy prices at Mid-C to the forecast developed by the NPCC. It also illustrates an adjusted NWE forecast, if AECO 2015 natural gas prices are applied to the market heat rate projections implicit in the NWE forecast. Because the NPPC forecast is objectively and independently determined, and fundamentally reflects underlying structural changes anticipated in Pacific Northwest power markets, PMRG believes it represents a better basis for determining Greycliff avoided cost, compared to the NWE electricity price forecast. NWE, and the PSC should strongly consider use of the NPPC forecast.

Q. HAS NWE MADE ANY DOWNWARD ADJUSTMENTS TO ITS AVOIDED COST CALCULATIONS? IF SO, ARE THEY APPROPRIATE?

A. NWE has made a number of downward adjustments to its "base" avoided cost calculation. Those adjustments were identified earlier in this report, in Table 3, and are repeated again below, for ease of reference. I will discuss each of these adjustments in order, and include a brief discussion of why these downward adjustments are inappropriate.

Table 5 – NWE Energy Proposed Greycliff Avoided Cost – Environmental Attributes Included

Variable	**Levelized Avoided Cost Impact ($/MWh)**
Energy Average Avoided Cost	$42.82
DA Firm vs. RT Price	($2.23)
Interconnection Network Upgrades	($4.54)
Regulation	($0.41)
Spinning Reserves	($0.59)
Supplemental Reserves	($0.95)
Avoided Cost (Offer)	**$34.09**

The first adjustment proposed by NWE represents a deduction in avoided cost of $2.23/MWh, to reflect the difference between Day-Ahead Firm power prices, and Real-Time power prices. The rationale behind this adjustment is not clear, but Mr. LaFave claims that the adjustment is necessary because in his view, the reported energy prices at Mid-C are Firm, and energy production from Greycliff would be non-firm, given the intermittency of generation from a renewable resource. Mr. LaFave analyzes historical differences in reported Day-Ahead and Real-Time power prices at Mid-C, and uses that difference to calculate a downward adjustment to avoided cost.

In my opinion, Mr. LaFave's downward adjustment calculation has little factual basis and is therefore an inappropriate deduction to avoided cost. First of all, NWE does not assign any capacity value to Greycliff in its determination of avoided cost. NWE's PowerSimm simulation and following analysis do not reflect capital costs of new resources, and do not provide Greycliff with any capacity value. In contrast, in past PSC rulings, wind resources were first given a 15% capacity credit, based on the avoided capital cost of a natural gas-fueled combined-cycle, and more recently were assigned a 5% capacity credit. Because Mr. LaFave did not provide a capacity value in his projection of Greycliff avoided cost, he is already treating the resource as non-firm. Mr. LaFave's calculation is therefore double counting.

Second, there is *no* formal real-time energy market at Mid-C. Instead, NWE is relying upon services that survey market participants at Mid-C, and provide summaries of reported bilateral transactions. The data underlying Mr. LaFave's calculation are based on low volume, reported transactions. Data sources like that, particularly for real-time transactions, are typically of low validity, and not representative of underlying market fundamentals. The major power providers in the Pacific Northwest do not rely upon "real-time" transactions at Mid-C to balance the power system, and instead they rely upon hydro assets and owned generation to provide balancing and regulation services.

The second major adjustment to avoided cost proposed by NWE, is a $4.54/MWh deduction to reflect the cost of Transmission Network Upgrades. Mr. LaFave proposed this adjustment in supplemental testimony. This proposed adjustment is in violation of non-discrimination policies established by the Federal Energy Regulatory Commission (FERC), and should not be included in determining Greycliff's avoided cost. FERC transmission policy is very clear, in assigning the cost of network upgrades to project developers during the development stage, but then requiring the transmission provider to refund those costs, with interest, at the time a project achieves commercial operation. NWE's proposed adjustment for those costs is counter to FERC policy, and unfairly discriminates against QF resources. This adjustment should not be included in determination of avoided cost for Greycliff.

NWE also includes 3 additional proposed avoided cost adjustments for regulation, spinning and supplemental reserves. In total, those adjustments aggregate to $1.95/MWh. NWE describes these adjustments as appropriate to reflect wind integration costs that will be faced on its system associated with Greycliff. NWE's PowerSimm simulations appear to have included stochastic modeling of load, generator outages, and wind generation levels. As such, the stochastic modeling completed by NWE *already* reflects wind integration dynamics, and, incidentally, also reflects many of the same fundamentals that NWE seeks to measure with the Day-Ahead/Real-Time adjustment discussed above.

While the NWE simulation approach already reflects wind integration aspects, at least this adjustment being proposed by NWE has precedent in PSC policy. The PSC has allowed wind integration adjustments to avoided cost in its past determinations. Based on its most recent major avoided cost decision, PMRG's reading of the appropriate adjustment is $1.4919/MWh, calculated as illustrated in Table 6:

Table 6 – Wind Integration Charge – Adjustment to Avoided Cost

Wind Integration		
W1-1 Tariff	>60 miles from Judith Gap	
	$0.26/kW/Mo	
	$78,000	per year at 25 MW
	$0.8859	*per MWh*
CR-1 Tariff	$10.10	$/MWh
	$0.30	3% of Integrated Hourly Generation
	$0.30	3% of Load Served by Generation
	$0.61	*Total Contingency Reserves*
Total Integration	**$1.4919**	**MWh**

The wind integration charges listed in Table 6 are based on the posted W1-1 and CR-1 tariffs, posted on the NWE website. Based on the most recent PSC major order on avoided cost, an adjustment of $1.4919/MWh appears to be appropriate, compared to NWE's larger adjustment of $1.95/MWh.

Q. HAS NEW MADE ANY REVISIONS TO ITS METHODOLOGY, OR PROVIDED AN UPDATED AVOIDED COST ESTIMATE?

A. Yes. Mr. LeFave and Mr. Hanson filed Supplemental Testimony Dated March, 2016, which included a number of adjustments.

Q. CAN YOU PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE SUPPLEMENTAL MARCH 2016 TESTIMONY?

A. Yes. The first set of adjustments described in Mr. LeFave's testimony was made to reflect an updated Commercial Operation Date, and updated estimated energy production levels from Greycliff. This adjustment reflects a 2018 Commercial Operation Date for the project, and expected annual generation of 88,044 MWh. These two adjustments are appropriate.

The second major adjustment proposed by Mr. LeFave was to change the date of his underlying forward power price forecast, to January 15, 2016, rather than the date July 6, 2015 which had been used in his previous analysis. Mr. LeFave states his belief that because Greycliff provided an updated COD, that it is appropriate to change the date of the underlying power price forecast. Mr. LeFave states that changing the power price forecast date, in isolation, reduces his updated levelized avoided cost projection by $3.80/MWh. I believe this adjustment is inappropriate, as Greycliff has previously established a LEO, and the date when the LEO was established, or a date near then, is more appropriate for use in developing an avoided cost estimate for Greycliff.

The third major adjustment proposed by Mr. LeFave was to include a capacity value component for Greycliff in his avoided cost projection. That adjustment increases Mr. LeFave's avoided cost incrementally by $1.98/MWh. Mr. LeFave's inclusion of a capacity value for Greycliff occurred in response to suggestions made by Greycliff on a conference call, and is appropriate.

Mr. LeFave also updated his estimated "adjustments" to avoided cost, presumably to reflect his new date for the underlying power price forecast. I have already addressed concerns about these adjustments earlier in this testimony. In addition to those concerns, it is not appropriated to update these estimates because the underlying power price forecast date used by Mr. LeFave should remain at July 6, 2015.

Q. WHAT AVOIDED COST VALUES DID MR. LEFAVE PROPOSE IN HIS MARCH 2016 SUPPLEMENTAL TESTIMONY?

A. Mr. LeFave's updated avoided cost projections are listed below in Table

Table 6 – NWE Energy Proposed Greycliff Avoided Cost – Environmental Attributes Included (Updated Supplemental Testimony March 2016)

Variable	Levelized Avoided Cost Impact ($/MWh)
Energy Average Avoided Cost	$43.28
DA Firm vs. RT Price	($1.99)
Interconnection Network Upgrades	($5.02)
Capacity Value	$1.98
Regulation	($0.52)
Spinning Reserves	($0.61)
Supplemental Reserves	($1.09)
Avoided Cost (Offer)	**$36.04**

Q. DID NEW DEVELOP AN ALTERNATIVE UPDATED AVOIDED COST ESTIMATE, IN RESPONSE TO GREYCLIFF'S MOST RECENT DATA REQUEST?

A. Yes. In response to Greycliff's (REVISED) GWP-012 Data Request, NWE developed an alternative avoided cost estimate. In GWP-012, Greycliff requested that NWE make three changes and update its avoided cost projection. In the first change, the power price forecast date was to rely upon the July 6, 2015 date. In the second change, Greycliff requested that NWE use the NPCC Medium Natural Gas Price Forecast in developing its avoided cost estimate. Greycliff provided the specific natural gas prices to use. In the third change, Greycliff requested that the $5.02/MWh reduction in avoided cost for transmission network upgrade costs be removed.

NWE filed a data response on April 20, 2016, and reported that with the three changes requested by Greycliff, the NEW avoided cost methodology results in a projected levelized avoided cost of $47.60/MWh.

Q. DO YOU HAVE ANY CONCERNS WITH THE DATA RESPONSE FILED BY NWE IN RESPONSE TO GREYCLIFF'S (REVISED) GWP-012 DATA REQUEST?

A. Yes. In its data response, NWE claims that the representation of the NPCC Medium Natural Gas Price Forecast provided by Greycliff has higher reported prices than a natural gas price forecast it received directly from NPCC. Greycliff requested clarification about this statement with NWE's attorney, and was provided a representation of the NPCC Medium Natural Gas Price Forecast directly from NWE. In the forecast data provided by NWE, the NPCC natural gas price forecast is labeled as being expressed in constant year dollars, with no general inflation adjustment. This is a mistake, as the avoided cost projections for Greycliff are prepared in nominal, year of occurrence dollars. In providing the NPCC Medium Natural Gas Price Forecast, Greycliff applied a general inflation rate of 2% annually. That inflation adjustment is appropriate, and appears to be the different interpretation of reported NPCC natural gas prices.

Q. IN LIGHT OF THE FOREGOING ANALYSIS, DO YOU FIND NWE'S AVOIDED COST ESTIMATE FOR GREYCLIFF REASONABLE AND CREDIBLE?

A. No. Given the lack of transparency in the PowerSimm model and the statistical parameters applied by it, and the relative lack of clarity about what the stochastic modeling utilized by NWE purports to address, I believe a simpler and more repeatable methodology for new large QFs like Greycliff is in order. I believe the original avoided cost estimate prepared by NWE, and the updated avoided cost estimate prepared in March, 2016, both understate the actual avoided cost that should be applied to Greycliff.

Q. AS DISCUSSED PREVIOUSLY, YOU PREPARED A DIFFERENT AVOIDED COST FORECAST FOR GREYCLIFF WHICH YOU FEEL MORE APPROPRIATELY CALCULATES AVOIDED COSTS FOR THE GREYCLIFF PROJECT?

A. Yes. I developed an avoided cost for the Greycliff project which I feel more appropriately captures NWE's avoided costs. The benefits of this approach is that the components of the forecast are developed and published by a neutral third party (NPCC), and do not have any of the defects that I have identified in my review of NWE's avoided cost approach.

Q. WHAT IS YOUR PROPOSED AVOIDED COST FOR THE GREYCLIFF PROJECT AND HOW WAS IT DEVELOPED?

A. Given the critique of the NWE methodology set forth previously in my testimony, I believe that NWE's proposed avoided cost for Greycliff is significantly lower than its actual avoided cost. This is due to the methodology employed by NWE, and due to two major proposed deductions from avoided cost that should not be included.

PMRG has developed alternative avoided cost estimates, based on the analyses described above. PMRG's recommended levelized avoided cost is \$53.39/MWh. This forecast reflects the NPCC medium level electricity price forecast, and the wind integration charges listed in Table 6. The forecast also reflects a 5% capacity credit assigned to Greycliff, based on the avoided capital cost of a LMS100 simple cycle power plant, which is a likely addition in NWE's next resource plan, given the size of its system, and the addition of wind and hydro resources onto its system since the time it last developed a resource plan. The inclusion of capacity value increases the avoided cost for Greycliff by \$1.78/MWh. Mr. LeFave's proposed capacity value for Greycliff of \$1.98/MWh would be an appropriate alternative. PMRG's estimate also includes an adjusted energy production level for Greycliff, of 88,043 MWh per year, which is the most current estimate of actual production levels.

PMRG also developed an alternative avoided cost estimate using the EIA 2015 AEO natural gas price forecast, applied to the spark-spreads implicit in NWE's forecast. This approach is designed to reflect PSC direction to NWE in developing avoided cost estimates. It results in a substantially higher avoided cost, at $80.82/MWh. The detailed calculations underlying those avoided cost estimates are outlined in Tables 7 and 8.

Table 7 – Greycliff Avoided Cost – NPCC Medium Level Forecast

NWE Energy Costs - NWPP Medium - Case - with Operating Reserves

NPV Of Avoided Costs	$54,629,871
Levelized Payment	$ 53.39

WACC 7.03% nominal, annual

Incremental Pricing

Year	Greycliff Generation (MWh)	Energy Average Avoided Cost ($/MWh)	DA Firm vs. RT price	Interconnection Network Upgrades	Regulation 25 Year Levelized	Spinning Reserve Service (BA Tariff)	Supplemental Reserves Service (non-spin; BA Tariff)	Capacity Credit (5% ELCC) ($/MWh)	Annual Avoided Cost Payment ($)
2018	88,043	$ 35.66	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,164,642
2019	88,043	$ 36.98	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,281,013
2020	88,043	$ 38.36	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,402,540
2021	88,043	$ 41.33	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,663,496
2022	88,043	$ 42.94	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,805,420
2023	88,043	$ 45.08	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	3,994,198
2024	88,043	$ 47.00	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,163,246
2025	88,043	$ 48.93	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,333,077
2026	88,043	$ 51.51	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,560,077
2027	88,043	$ 53.65	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,748,135
2028	88,043	$ 55.17	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,881,963
2029	88,043	$ 57.38	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,077,229
2030	88,043	$ 59.73	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,283,645
2031	88,043	$ 61.33	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,424,687
2032	88,043	$ 63.76	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,638,416
2033	88,043	$ 66.45	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,875,097
2034	88,043	$ 68.79	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,081,776
2035	88,043	$ 71.45	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,315,651
2036	88,043	$ 74.11	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,549,527
2037	88,043	$ 76.76	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,783,402
2038	88,043	$ 79.42	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,017,277
2039	88,043	$ 82.08	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,251,152
2040	88,043	$ 84.73	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,485,027
2041	88,043	$ 84.73	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,485,027
2042	88,043	$ 84.73	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,485,027

Table 8 – Greycliff Avoided Cost – NWE Forecast, Adjusted for AEO Natural Gas Prices

NWE Energy Costs - Adjusted for AEO Natural Gas Prices - With Operating Reserve Adjustments

NPV Of Avoided Costs	$ 82,702,686		
Levelized Payment	$ 80.82	WACC	7.03% nominal, annual

Incremental Pricing

Year	Greycliff Generation (MWh)	Energy Average Avoided Cost ($/MWh)	DA Firm vs. RT price	Interconnection Network Upgrades	Regulation - 25 Year Levelized	Spinning Reserve Service (BA Tariff)	Supplemental Reserves Service (non-spin; BA Tariff)	Capacity Credit (5% ELCC) ($/MWh)	Annual Avoided Cost Payment ($)
2018	88,043	$ 50.23	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,447,667
2019	88,043	$ 55.30	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	4,894,209
2020	88,043	$ 62.01	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,484,615
2021	88,043	$ 66.15	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	5,849,467
2022	88,043	$ 69.31	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,127,433
2023	88,043	$ 71.32	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,304,188
2024	88,043	$ 73.28	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,477,143
2025	88,043	$ 78.61	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	6,946,330
2026	88,043	$ 82.62	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,299,501
2027	88,043	$ 84.69	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,481,754
2028	88,043	$ 84.50	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,464,457
2029	88,043	$ 85.69	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,569,332
2030	88,043	$ 87.55	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,733,139
2031	88,043	$ 89.72	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	7,924,583
2032	88,043	$ 93.27	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	8,236,888
2033	88,043	$ 96.12	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	8,487,834
2034	88,043	$ 99.54	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	8,789,175
2035	88,043	$ 104.20	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	9,199,445
2036	88,043	$ 108.63	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	9,588,750
2037	88,043	$ 112.50	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	9,930,191
2038	88,043	$ 117.32	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	10,354,347
2039	88,043	$ 123.29	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	10,879,738
2040	88,043	$ 123.32	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	10,882,858
2041	88,043	$ 123.32	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	10,882,858
2042	88,043	$ 123.32	$ -	$ -	$ (0.89)		$ (0.61)	$ 1.78	10,882,858

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

RESPECTFULLY SUBMITTED this 29th day of April, 2016.

UDA LAW FIRM, PC

By:______________________
Michael J. Uda
Attorney for Greycliff Wind Prime, LLC

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served on this29 th day of April, 2016 upon the following by first class mail postage pre-paid:

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I hereby certify an original was e-filed, and six copies of the foregoing were hand-delivered to the following:

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Jackie Haskins-Legal Assistant